NORSOK STANDARD

DRILLING & WELL OPERATIONS

D-010
Rev. 2, December 1998

Norwegian Technology Standards Institution
Oscarsgt. 20, Postboks 7072 Majorstua
N-0306 Oslo, NORWAY

Telephone: + 47 22 59 01 00 Fax: + 47 22 59 01 29
Email: norsok@nts.no Website: http://www.nts.no/norsok

CONTENTS

FOREWORD

NORSOK (The competitive standing of the Norwegian offshore sector) is the industry initiative to add value, reduce cost and lead time and eliminate unnecessary activities in offshore field developments and operations.

The NORSOK standards are developed by the Norwegian petroleum industry as a part of the NORSOK initiative and supported by OLF (The Norwegian Oil Industry Association) and TBL (Federation of Norwegian Engineering Industries). NORSOK standards are administered and issued by NTS (Norwegian Technology Standards Institution).

The purpose of NORSOK standards is to contribute to meet the NORSOK goals, e.g. by replacing individual oil company specifications and other industry guidelines and documents for use in existing and future petroleum industry developments.

The NORSOK standards make extensive references to international standards. Where relevant, the contents of a NORSOK standard will be used to provide input to the international standardisation process. Subject to implementation into international standards, the NORSOK standard will be withdrawn.

INTRODUCTION

The main objective of this NORSOK Standard is to contribute to an optimisation of the drilling & well operations with respect to gaining operational efficiency and to stipulate an acceptable safety level.

Revision 2 of this Standard is an overall improvement and expansion of the former D-010, especially on well intervention and pressure control drilling.

1 SCOPE

This NORSOK standard defines functional and performance oriented requirements for well design and planning and execution of safe and efficient drilling and well operations in Norwegian waters.

2 NORMATIVE REFERENCES

The following standards include provisions which, though reference in this text, constitute provisions of this NORSOK standard. Latest issue of the references shall be used unless otherwise agreed. Other recognised standards may be used provided it can be shown that they meet or exceed the requirements of the standards referenced below.

NORSOK M-702	Drill string components
NORSOK S-002	Working Environment
NORSOK S-003	Environmental Care
NORSOK Z 015	Temporary Equipment
NORSOK D-001	Drilling Facilities
NORSOK D-CR-003	Surface Christmas Tree, Rev. 1 Jan. 1995
NORSOK D-SR-005	Coiled tubing equipment, Rev 1, Jan. 1996
NORSOK D-SR-006	Snubbing equipment, Rev. 1, Jan. 1996
NORSOK D-SR-007	Well testing system, Rev. 1, Jan. 1996
NORSOK D-SR-008	Wireline equipment Rev. 1, Oct. 1996

BS 6755: Part 1: 1986 (1991) = ISO 5208 Specification for production pressure testing requirements

NACE MR0175	Sulphide Stress Cracking Resistant Metallic Materials for Oilfield Equipment, 1997
NPD	Acts, Regulations and Provisions for the Petroleum Activity
ANIS/ASME B31.3	Process Piping, 1996
ISO 10407	Petroleum and Natural Gas Industries – Drilling and Production Equipment – Drill Storm Design and Operating Limits First Edition, 1993
ISO 10417	Petroleum and Natural Gas Industries – Subsurface Safety Valve Systems – Design Installation, Operation and Repair First Edition, 1993
ISO 10423	Petroleum and Natural Gas Industries – Drilling and Production Equipment – Specification for Valves, Wellhead and Christmas Tree Equipment First Edition, 1994
ISO 10432	Petroleum and Natural Gas Industries – Subsurface Safety Equipment – Specification First Edition, 1993

ISO 10433	Petroleum and Natural Gas Industries – Drilling and Production Equipment – Specification for Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service First Edition, 1994
API Bull 6AR	Recommended Practice for Repair and Remanufacture of Wellhead and Christmas Tree Equipment, 1994
API Spec 6FA	Specification for Fire Test for Valves, 1994
API Bull 6FI	Bulletin on Performance of API and ANSI End Connections in a Fire Test According to API Specification 6FA, 1994
API Bull 6F2	Bulletin on Fire Resistance Improvements for API Flangas, 1994
API RP2K	Bruk av stigerør
API Bull 2J	Stigerørsanalyse
API Spec 10	Specification for Materials and Testing for Well Cements, 1990
API Spec 10D	Specification for Bow-Spring Casing Centralises, 1995
API RP 10E	Recommended Practice for Application of Cement Lining to Steel Tubular Goods, Handling, Installation and Joining Third Edition; ISO 10409, 1994
API Spec 13A	Specification for Drilling Fluid Materials, 1993
API RP 138-1	Recommended Practice Standard Procedure for Field Testing Water-Based Drilling Fluids, 1990
API RP 138-2	Recommended Practice Standard Procedure for Field Testing Oil-Based Drilling Fluids, 1991
API RP 13C	Recommended Practice for Drilling Fluid Processing Systems Evaluation, 1996
API RP 13D	Recommended Practice on the Rheology and Hydraulics of Oil-Well Drilling Fluids, 1995
API RP 13E	Recommended Practice for Shale Shaker Screen Cloth Designation, 1993
API RP 13G	Recommended Practice Standard Procedure for Drilling Mud Report Form, 1991
API RP 13I	Recommended Practice Standard Procedure for Laboratory Testing Drilling Fluids, 1995
API RP 13J	Testing of Heavy Brines, 1996
API RP 14B	Design, Installation, Repair and Operation of Subsurface Safety Valve Systems Fourth Edition; ISO 10417; Errata – 1996, 1994
API Spec 14D	Specification for Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, 1994
API RP 14H	Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore Fourth Edition; ISO 10419, 1994
API RP 17A	Recommended Practice for Design and Operation of Subsea Production Systems, 1996
API RP 53	Blow-out Prevention Equipment Systems for Drilling Wells Third Edition, 1997

API Spec 5CT	Specification for Casing and Tubing (Metric Units) Fifth Edition, 1995
API Spec 5D	Specification for Drill Pipe, 1992
API Spec 5B	Specification for Threading, Gauging and Thread Inspection of Casing, Tubing and Line Pipe Threads (U.S. Customary Units), 1996
API Spec 5L	Specification for Line Pipe, 1995
API Spec 5LC	Specification for CRA Line Pipe, 1995
API Bull 5A2	Bulletin on Thread Compounds for Casing, Tubing and Line Pipe Sixth Edition; Superseded by RP5A3, 1988
API Bull 5C2	Bulletin on Performance Properties of Casing, Tubing and Drill Pipe, 1987
API Bull 5C3	Bulletin on Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties, 1994
API Bull 5C4	Bulletin on Round Thread Casing Joint Pressure and Bending, 1987
API RP 5A5	Recommended Practice for Field Inspection of New Casing, Tubing and Plain-End Drill Pipe, 1993
API RP 5B1	Gauging and Inspection of Casing, Tubing and Line Pipe Treads Fourth Edition, 1996
API RP 5C1	Recommended Practice for Care and Use of Casing and Tubing, 1994
API RP 5C5	Evaluation Procedures for Casing and Tubing Connections
API Spec 6D	Specification for Pipeline Valves (Gate, Plug, Ball and Check Valves), 1994
API Spec 6FB API	Specification for Fire Test for End Connections, 1992
API Spec 6FC	Specification for Fire Test for Valves with Automatic Backseats, 1994
API Spec 16A	Specification for Drill Through Equipment, 1986 (replace with ISO 13533 when issued)
API Spec 14A	Specification for Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service First Edition, 1994
API RP 14B	Design, Installation, Operation and Repair First Edition, 1993
API RP 14E	Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, 1991
API STD 607	Fire Test for Soft-Seated Quarter Turn Valves, 1993
API Spec 16D	Specification for Control Systems for Drilling Well Control Equipment, 1993
API Spec 7	Specification for Rotary Drill Stem Elements Thirty Eight Edition; Errata – 1994 (replace with ISO 10424 when issued)
API Spec 7F	Specification for Oil-Field Chain and Sprockets, 1993
API RP 7G	Drill Stern Design and Operating Limits First Edition, 1993
API Spec 8C	Specification for Drilling and Production Hoisting Equipment (PSL 1 and PSL 2), 1992 (replace with ISO 13535 when issued)

API RP 8B	Recommended Practice for Procedures for Inspection, Maintenance, Repair and Remanufacture of Hoisting Equipment, 1992
API Spec 9A	Specification for Wire Rope, 1995
API RP 9B	Recommended Practice on Application, Care and Use of Wire Rope for Oil Field Service, 1986
API RP 10E	Recommended Practice for Application of Cement Lining to Steel Tubular Goods, Handling, Installation and Joining Third Edition; ISO 10409, 1994
API RP 5C7	Coiled Tubing Operations in Oil and Gas Well Service First Edition, 1996

3 DEFINITIONS AND ABBREVIATIONS

3.1 Definitions

Barrier: One or several dependent barrier elements, which are designed to prevent unintentional flow of formation fluid.

A barrier is an envelope preventing hydrocarbons from flowing unintentionally from the formation, into another formation or, to surface.

Barrier elements that make up the Primary barrier are those elements, which are or might be in direct contact with well pressure during normal operation. These elements provide the initial and inner envelope preventing unintentional flow of reservoir fluid to surface, or another zone.

Barrier elements that make up the Secondary barrier are those, which are or might be exposed to contact with well pressure should any of the elements described as a Primary barrier element fail. These elements provide an envelope outside the Primary barrier envelope providing a second barrier preventing unintentional flow of reservoir fluid to surface, or another zone.

HPHT well: Well drilled in a formation with expected shut-in wellhead pressure greater than 690 bar and/or bottom hole temperature in excess of 150° C.

NORSOK: Norsk Sokkels Konkurranseposisjon, the Competitive standing of the Norwegian Offshore Sector, the Norwegian initiative to reduce cost on offshore projects.

Shall: Verbal form used to indicate requirements strictly to be followed in order to conform to the standard and from which no deviation is permitted, unless accepted by the Operator.

Should: Verbal form used to indicate that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others, or that a certain course of action is preferred but not necessarily required.

Simultaneous operations: Two or more major activities being in process parallel in time.

Tested barrier: Barrier tested and qualified to withstand maximum expected pressure.

Pressure controlled drilling: A well drilled under the conditions that the effective pore pressure in the formation is greater than the static/effective circulating downhole pressure, of a drilling fluid (flow drilling).

3.2 Abbreviations

AFE	Approval for Expenditure
BHA	Bottom Hole Assembly
BOP	Blow Out Preventer
BPV	Back Pressure Valve
CDRS	Common Drilling Reporting System
CT	Coiled Tubing
CTD	Coiled Tubing Drilling
DSHA	Defined Situations of Hazard and Accidents
ECD	Equivalent Circulating Density
ESD	Emergency Shut Down
HMV	Hand Manual Valve
HPHT	High Pressure High Temperature
HSE	Health, Safety and Environment
HXT	Horizontal x-mas tree
IADC format	International Association of Drilling Contractors
IBOP	Internal Blow Out Preventer
IT	Information Technology
IWCF	International Well Control Forum
JPD	Jointed Pipe Drilling
LCC	Life Cycle Cost
LMRP	Lower Marine Riser Package
LRP	Lower Riser Package
LWD	Logging while Drilling
MSL	Mean Sea Level
MUT	Make up Torque
MWD	Measurement while Drilling
NMCE & R	Norwegian Ministry of Church, Education and Research
NMD	Norwegian Maritime Directorate
NPD	Norwegian Petroleum Directorate
OD	Outer Diameter
PCD	Pressure Control Drilling?
PL	Production Licensee
PSD	Production Shut Down
QRA	Quantitative Risk Assessment
RKB	Rotary Kelly Bushing
ROV	Remote Operated Vehicle
SAM	Regulation relating to systematic follow-up of the working environment (Deleted!)
SCSSV	Surface Controlled Subsurface Safety Valve
SEPREA	Specific Emergency Preparedness Requirements for the Activity
SFT	Surface Flow Tree
SJA	Safe Job Analysis
SPCA	State Pollution Control Agency (Statens Forurensingstilsyn)

SSTT	Sub Sea Test Tree
TKV	Tubing Kill Valve
TLP	Tension Leg Platform
WHP	Well Head Pressure?
WL	Wire Line
X-mas tree	Production Control and Safety Valve Arrangement

4 GENERAL REQUIREMENT

4.1 Well Classification

Registration number, well identification and classification or reclassification shall be obtained from the NPD for each well before any operations commence.

4.2 Well Design

4.2.1 Formation Data

The well design shall be based on the following:

- Geological prognosis
    * Expected stratigraphy and lithology
    * At least two interpreted deep seismic cross – section views through the field or planned well path
    * Geological description of all prospects
    * Geological uncertainties
    * Site survey
- Fluid contact prognosis
- Requirements to zonal isolation
- Temperature, pore pressure and formation strength prognosis
- Well path and target requirements
- Potential well collosion risks
- Hole cleaning and hole stability requirements
- Production or injection requirements
- Design life requirements

4.2.2 Well Design Process

Prior to commencing the detailed well design process, the following considerations should be part of a conceptual plan:

- Outline Well
    * Define well type
    * Define total lifecycle of well
    * Policies, procedures, standards and controls in place and adequate
- Rig suitability
- Review offset data
    * Obtain and analyse offset data, identify areas requiring more detailed follow up
- Evaluate risk for shallow gas and hydrates
- Wellpath design

- Casing design
  * Review formations, pore pressures, formation strengths and temperature gradients
  * Prepare preliminary design
  * Check design for shallow hazard implications

- Completion
  * Review completion equipment with respect to artificial lift requirements, packers, plugs etc.
  * Testing pressure
- Formation Evaluation
- HPHT Evaluation
- Cold Climate Evaluation
- Tubing design
  * Test pressure
  * Materials selection
  * Packer envelope
- Well test requirements
- Manning or training
- Logistics and materials
- HSE
  * Identify environmental sensitivities
  * Hazard or risk identification and handling
- Review design
- Approve design

4.2.3 Drilling Location

A site survey including an assessment of sea bed conditions, water depths, boulders, subsidence, seabed features, possible obstructions, cables, pipelines, anchor holding demands, sea traffic, etc. of concern shall be performed and thoroughly interpreted. The survey shall also cover possible surface locations for relief wells.

The seismic lines shall have a penetration covering the geological sequence to the setting depth for casings for the blowout preventer. Connecting seismic lines to neighbouring wells shall be established if practically possible.

4.2.4 Site Specific Considerations

Orientation and protection of the facilities should be optimised with regard to prevailing meteorological and oceanographic conditions and with due regard to emergency preparedness.

Efforts should be made to eliminate the need to place anchors closer than 500 m off other platforms or subsea installations, and 200 m off pipelines and cables, assuming direction of pull is away from these facilities. Any deployment of anchor or anchorline closer than these distances requires special safety considerations and clarifications to be undertaken if the other Owners or Operators and NPD has consented to the precautions being taken. Increased distances or clearances and additional safety precautions are required where direction of pull is towards other installations or pipelines or cables. Prior to start planning of these operations, operators of exposed platforms, sub sea installations or pipelines and cables shall be notified.

When drilling a well close to a lease line, the position uncertainties for well path or surface location should be taken into account in order not to compromise the lease line. When drilling adjacent to boarder lines to neighbouring countries, international agreements must be observed.

For floating units the station keeping capabilities must be verified to be within set criteria (with due consideration to possible anchoring or positioning failure), and it is mandatory to be able to immediately move off location in a shallow gas emergency. For other DSHA the SEPREA's and procedures defined by the operator will apply.

4.3 Well Data Acquisition

4.3.1 General

During operations data related to geology, reservoir and drilling shall be collected or recorded in order to facilitate evaluation of geology and prospects, operational control or optimisation and experience transfer.

An evaluation of the data acquisition programme shall be done prior to every specific drilling operation in order to comply with the purpose of and requirements for the well.

In order to optimise the value and use of data, quality assurance, storage, media, availability etc. should be focused.

For a drilling operation the following minimum requirements shall apply:

4.3.2 Geological and reservoir technical

Data	**Requirements**
Drill Cuttings	Unwashed (1 kg) and washed and dried (10-20 g). Min. 10 m intervals, 3 m intervals in expl wells in HC bearing zones.
Cores	<u>Exploration wells</u>: Min. 1 core in all HC bearing zones and cores from potential source rocks and reservoir rocks. <u>Appraisal wells</u>: Complete reservoir section in selected wells <u>Production wells</u>: A representative selection of wells from the reservoir and source rocks.
Side wall cores	Optional
Fluid, gas and res. formation water samples	From individual test intervals. <u>Surface sampling</u>: Pressure, temperature and flow rate to be recorded. <u>Bottom hole sampling</u>: 2 corresponding samples. Pressure, temperature and flow rate to be recorded. Surface samples may be sufficient if recombination gives correct fluid composition
Logs/LWD	<u>Drilling</u>: Min. to facilitate evaluation of lithology, porosity, water saturation, <u>Formation test</u>: Min. to establish pressure gradient, type of fluids, productivity and temperature.

4.3.3 Drilling

Data	Requirements
Well integrity	Data for verification of integrity of well barriers i.e. BOP's, wellhead, casings, cement jobs etc.
Directional	Continuous (for every stand drilled) registration of inclination and azimuth.
Formation pressure	All necessary data to be recorded after installation of conductor or surface casing.
Formation strength	LOT/FIT after casings have been drilled out.
Operational	Rig data aq. system, Mud data, Mud Logs, MWD logs etc. Ref. also NORSOK Standard D-001, Drilling. An evaluation of the data acquisition requirements shall be identified for each individual well.

4.4 Blow-out Contingencies or Relief Well Drilling

4.4.1 General

The blowout contingency plan shall be developed to meet the NPD legislation as well as Operator internal requirements. The document shall be regularly updated to assure that relevant information is available in case of well control. It shall contain the following:

- Mobilisation of necessary emergency equipment, personnel, services
- Kill methods in the case of a blowout occurrence.
- Description of suitable locations for drilling a relief well
- Measures for limiting the amount of the damage from the hazard or accident
- Guidelines for normalisation of the operation

4.4.2 Relief Well

If a surface intervention cannot be performed on the blowing well the blowing shall be killed or plugged via a relief well. The objective of a relief well is to enter or get communication to dynamically kill and stabilise a blowing well.
The following items shall as a minimum be covered for a relief well design:

- Mapping of suitable drilling locations if appropriate including shallow seismic interpretation of the top section
- Evaluation of blow-out scenarios and kill methods
- Requirements to facilities for relief drilling and well killing
- Evaluation of relevant well profiles and casing programme
- Estimation of necessary pumping capacity
- Updated list of available equipment and time critical activities, including possible rigs or facilities for well intervention options as appropriate.

Initiation of relief drilling at a relevant location shall commence no later than 12 days after the option is declared.

4.5 Barrier Philosophy

4.5.1 Primary Requirements

All Operators shall establish and implement a barrier philosophy to meet the NPD legislation's, which shall be adapted also by companies or personnel working for or on behalf of the Operator. The operator should take the necessary steps to assure that the barrier philosophy is adapted, understood and used during operations.

During drilling or workover operations the fluid column or a plug is normally providing the primary barrier, with a secondary barrier available to be activated (typically BOP pipe ram or shear or blind ram)

No single failure of barrier or barrier element, whether caused by operational error or equipment failure, shall lead to loss of well control.

Two independent and tested barriers shall be available.

The two defined barriers shall to the extent possible be independent of each other without common barrier elements. If common elements exist procedures shall be established to govern operations and/or failure scenarios.

If one barrier fails, immediate measure shall be taken in order to monitor an adequate safety level, until at best two independent and tested barriers have been restored. No other activity than re-establishment of the barrier shall be carried out in the well.

The barrier element shall be designed such that:

- Re-establishment of a lost barrier can be done quickly,
- The position or location and status can be known,
- It can be pressure tested, or verified by other means, e.g. observation,
- It is independent of other barriers in conjunction with the same source of influx,
- It can operate competently in the environment (pressure, temperature, and fluids) that may be encountered during the period it was intended for.

The barrier shall be positioned as close as possible to a potential influx.

As part of the planning of the operation there shall be prepared graphical barrier diagrams for the main operational stages clearly identifying primary and secondary barriers.

4.5.2 Testing of Barriers

Barriers shall as far as possible be tested in the direction of the potential flow.

The barrier shall be tested to the maximum anticipated differential pressure.

If high-pressure components, such as BOP rams, valves, seals and gaskets are replaced, these components shall be tested to working pressure.

Test pressures shall be specified in the Operations Programme.

Fluids acting as a barrier may be qualified as tested barriers when justified on the basis of the fluid specification, observation and stability testing of the fluid.

Inflow as tested barrier elements can be qualified as tested barriers.

Criteria shall be established to define the acceptance level for the leak rate while pressure or leak testing barrier elements.

4.5.3 Barrier Status

The position or status of the barrier or barrier element shall to the extent possible be known at all times. If not achievable, compensating measures shall be established.

Identification of the barriers shall be established prior to commencement of the activity by describing the barrier elements, planned location and method of monitoring.

All parameters relevant for maintaining the control of the well shall be monitored continuously.

Position or status of the barrier or barrier element shall be available through test record, lights or data printout presented to the driller and/or the principal operator of the equipment representing the barrier.

4.5.4 Barrier Availability

The availability of barrier elements shall be defined and documented.

When planning an activity, situations where barrier elements are not available (i.e. when running drill collars past a shear ram, which is not qualified for cutting) shall be identified.

Passive barrier elements that are dependent on energy to be activated shall be equipped with redundant supply, (accumulators, second electrical power source etc.)

4.5.5 Failure Criteria (Well Control Actions)

Prior to commencement of an activity, there shall be a plan of corrective action to be taken in case of failure of barrier elements.

A description of possible failure that can affect the barrier shall be described together with a contingency plan to re-establish the barrier.

Well control actions should regulate the use of shear ram or other cutting tools by identifying various options and use of barrier elements before the work string or wireline or coiled tubing is sheared.

Failure criteria for the barriers and barrier elements shall be described through presentation of contingency action flow diagrams representing those scenarios that are considered to potentially occur as a result of equipment or human failure during the activity.

4.6 Operations

4.6.1 Operations Planning

In due time before starting on operation, an approved project definition shall be available in writing.

All projects or operations shall be planned in accordance with the relevant Regulatory Bodies' rules and regulations and Company's relevant governing documents.

Solutions or methods shall be based on specifications given in the project definition, qualified experiences, available technology and cost or benefit analyses.

Life cycle cost (LCC) evaluations shall be reflected in the cost or benefit calculations.

Information made available for the operational environment shall give operational personnel a basis to make the decisions required for an optimal cost-effective operation, within the framework established by the HSE. This is particularly important during assignments where deviations from the programme or procedures could lead to a critical situation.
The information shall provide the basis for selecting the most optimal solutions during normal operations.

The planning and approval process shall be documented.

4.6.2 Back-up Equipment

Critical spare parts or back-up equipment with long lead-time should be identified and possibly planned to be located offshore or at the shore base.

4.6.3 Equipment Rig-up

Proper, formal interface with the rig systems for the offshore facilities must be established.
Norsok Standard Z 015 is considered as recognised standard in this context.

4.6.4 Contingency procedures

Approved contingency procedures shall have been reviewed prior to the operations phase. Both Company and contractor shall have these procedures available offshore.

Specific contingency procedures related to special applications, operations or equipment not covered in the contractors operational manual, shall be described in the work programme.

4.7 Preparation of Programme

Operation premises and a detailed description of the planned tasks to be executed shall be included in specific operations programmes for the operation in question.

Typical programmes to be developed are:
- Drilling programme
- Completion programme
- Testing programme
- Plugging programme
- Work-over programme
- Well intervention programme

Emphasis should be made on the use of explanatory formats and schematics flowcharts.

The programme shall have been subject to an inter-discipline check involving the Operator and the main Contractor(s) prior to implementation. The programme may be supplemented by more detailed guidelines and risk analyses.

As the operations proceeds, significant deviations from the programme shall be formally identified and recorded, and approved and the NPD informed where applicable.

Content	Programmes	Drilling Programme	Formation Test Programme	Completion Programme	Perforation/Isolation Programme	Intervention programme	Plugging Programme
General	Purpose of activity and time schedule	x	x	x	x	x	x
	Installation/vessel's name, PL number, block, field	x	x	x	x	x	x
	Well identification, classification	x	x	x	x	x	x
	Position (geolgraphical and seismic)	x					
	Waterdepth (MSL) and depth reference (RKB elevation)	x					
Organisation	Organization plan	x	x	x	x	x	x
	Resp. and com. during normal operation and emengencies	x	x	x	x	x	x
	List of contractors	x	x	x	x	x	x
Geology	Geological prognosis/information	x					
	Pressure prognosis/information	x					
	Plan for geological sampling/logging	x					
Reservoir	Reservoir data prognosis/information	x	x		x	x	
	Plan for reservoir technical sampling/logging	x	x		x	x	
	Perforation intervals, flow/shut-in periods		x	x	x	x	x
	Estimated rates, discharges, env. consequences		x		x		
	Plan for stimulation		x		x		
Technical	Casing/tubing programme/information	x		x		x	x
	Cementing programme/information	x		x		x	x
	Fluids programme/information	x		x		x	x
	Directional programme/information	x		x		x	x
Operational	Operational constraints and shutdown criterias	x	x	x	x	x	x
	References to operational procedures and instructions	x	x	x	x	x	x
	Detailed operational sequence	x	x	x	x	x	x
Safety	Detailed description of barriers/well contr. eq. for all phases	x	x	x	x	x	x
	Safety and operational hazards and planned measures	x	x	x	x	x	x
	Drills related to well safety	x	x	x	x	x	x
	Deviations from governmental and internal requirements	x	x	x	x	x	x

4.8 Risk Analyses

4.8.1 General

Prior to every operation and when evaluating the risk situation, a separate risk analysis shall be considered carried out.
Risk Analyses shall be carried out to expose the probability and consequence of single failures or sequential failures that may occur during operation. Risk analyses are normally split in two main categories:

- Installation specific Quantitative Risk Assessment (QRA), and
- Operational Risk Analyses

The risk analysis shall be performed before the operation is started. The risk analysis shall as far as possible incorporate previous experience with similar operations.

The analyses shall be carried out with the co-operation of personnel possessing sufficient operational experience as well as personnel possessing documented risk analysis experience to ensure that all relevant factors are taken into account. Relevant factors may include design of installation, available equipment (including barriers), organisational limitations, environment, geology, etc.

4.8.2 QRA

The QRA is performed as part of the design. The operator shall review the QRA to ensure that it is in line with all relevant standards and regulations, and that all significant modifications has been incorporated. The QRA shall reflect the conditions expected at the specific location.

4.8.3 Operational Risk Analyses

An operational risk analysis shall, when applicable, be performed:
- for new or non-standard operations
- for operations in new areas
- for operations to be performed by new or modified rig or installation
- for operations using new or modified equipment
- for operations including contractor(s) not familiar with the rig, area or operation
- if the operation are considered hazardous (e.g. HPHT or simultaneous operations, dynamic positioning, deep water, cold climate or reduced riser margin)

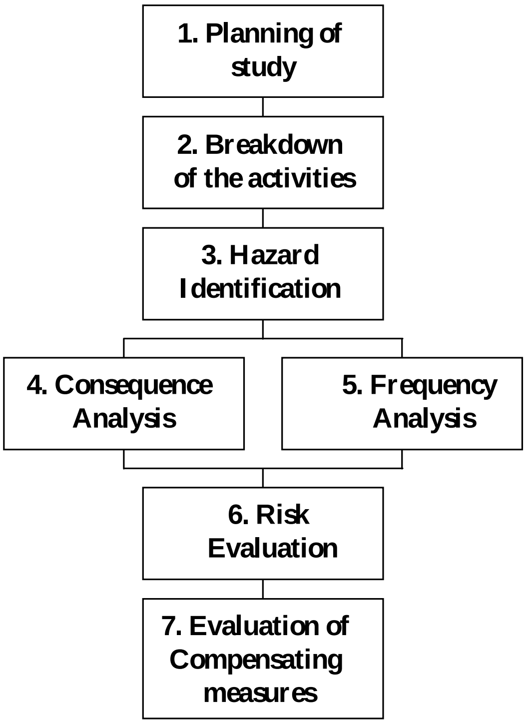
4.8.4 Task Analysis

Regular task analysis (SJA) shall be carried out to review hazards and consequences of operations and failures that may occur so that risk-reducing measures may be taken. Prior to every operation, introduction of new equipment and when evaluating change in premises, a separate analysis shall be considered carried out.

A safety meeting should be held to ensure all personnel are aware of the operational limitations applicable in connection with the operation. Specific meetings to be held as often as required for reviewing risk in the activities (SJA).

4.8.5 Methods

The assessment shall as a minimum include the following steps:



1 The planning shall as a minimum include type of method to be used, boundaries of study, and inclusion of relevant personnel. Risk Acceptance criteria shall be established at this stage.
2 In order to ensure an efficient and structured analysis, the various steps of the operation should be broken down and assumptions recorded.
3 The hazard identification shall systematically identify all potential technical, operational and organisational hazards.
4 The consequences of the identified hazards to personnel, environment and economy shall be identified.
5 The frequency of occurrence of each identified hazard shall be determined based on previous experience, standard methods or expert judgements.
6 Based on the estimated consequences and frequency of the identified hazards, the risk can be estimated and compared to the acceptance criteria.
7 Measures to control, reduce or remove the identified risk shall be evaluated. Probability reducing measures shall be given priority over consequence reducing measures.

Results from the risk analysis shall be communicated to the employees and shall be used actively in preventive safety efforts.

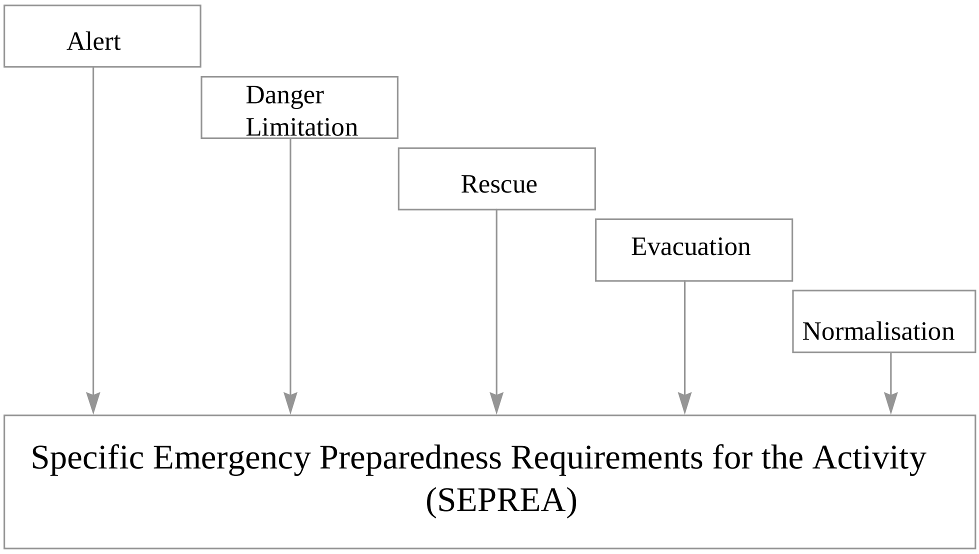
4.9 Emergency Preparedness Analysis

The emergency preparedness analysis shall ensure a systematic evaluation of all technical, operational and organisational measures which

- prevent a dangerous situation that has occurred from developing into an accidental event, or
- prevent or reduce the harmful effects of accidental events that have occurred.

Based on information obtained from the risk analysis, a set of defined situations of hazard and accident (DSHA) shall be identified, serving as a basis for establishing the emergency preparedness.

For each of the DSHA, a set of Emergency Preparedness requirements shall be identified for each phase of the emergency preparedness. This is illustrated below. The analysis shall result in a set of requirements related to the effectiveness of the emergency preparedness measures employed to meet the defined situations of hazard and accident.



Alert shall be carried out to ensure totally effective mobilisation of all relevant emergency preparedness resources.

Measures for danger limitations shall be implemented when a hazardous situation occurs in order to avoid it developing into an accident situation.

Rescue measures shall ensure that missing persons are found and that injured persons are given necessary first aid and brought to safe area for treatment.

Evacuation on and from the installation shall be carried out in a safe and organised manner in order that all personnel are brought to a safe area.

Normalisation measures shall ensure that personnel are brought ashore for treatment and care, the environment is restored to its normal condition and that damage to the installation is stabilised and the reservoir secured.

Verification of the emergency preparedness shall be performed to ensure that the Emergency preparedness requirements are met.

Requirements to emergency preparedness competence shall be defined for all personnel taking part in the activity concerned.

4.10 Application of Consents, Permits, Approvals

The consents necessary shall be obtained from NPD by the Operator, they are activity specific, and are typically related to the use of a particular installation at a certain area over a defined period. The assessments required to support and document the Application for Consent need to be a well-organised approach, with multi-discipline involvement from the Operator and Contractors.

The Operator is responsible towards the authorities, but the process assumes commitments from all parties involved. Any regulatory exemptions, for which the authority concurrence is requested, are typically detailed in the Application for Consent.

Details regarding the subsequent Permits, Approvals and submittal of programmes for specific drilling and well operations are outlined in the NPD's «Regulations for Drilling and Well Activities and Geological Data Collection, etc.». Activity plans, possible regulatory discrepancies and extraordinary HSE aspects should be highlighted by submission of these documents.

A Discharge Permit shall be obtained from the SPCA for exploration and field development operations.

4.11 Simultaneous Operations

Simultaneous operations shall be thoroughly planned, analysed and performed with the objective of limiting excessive risk imposed by multiple operations at the same time, as opposed to the risk associated with the execution of these operations individually. Relevant procedures for the control of simultaneous or parallel operations shall be developed and validated or assessed prior to commencement of operations.

4.11.1 Definition of Operations and Basic Safety Criteria

The following operations are defined as simultaneous operations if two or more of these operations are executed at the same time within the defined area for such activity:

- Production or Injection
- Live well operations
- Pigging operations exposing drilling and well area
- Running or pulling riser or heavy lifting or heavy construction
- Skidding rig
- Hot Work
- Drilling operations and workover
- Conductor driving and installation
- Injection to annulus
- Repair of change-out of X-mas tree or annulus valves
- Pumping and flowing through temporary lines

A prerequisite for executing simultaneous operations in a safe and prudent manner is emphasising administrative and operational procedures to ensure a systematic and controlled execution of the activities.

4.11.2 Operational Considerations

Operational measures to ensure that simultaneous activities are carried out in a safe manner should at least include the following considerations:

- Ensure that the day-to-day follow-up of simultaneous activities during the operational phase takes place in a co-ordinated and systematic way, and possible deviations are identified and corrected.
- If during drilling a well deviates within defined minimum distances to completed and perforated wells, correlated for the uncertainty of the position indication, barriers (plugs) shall be introduced below a possible point of contact in the said production or injection wells. If a possible point of contact is located above the SCSSV, closing and testing the SCSSV will be sufficient.
- The annular space of wells that may be exposed to collision with a well where drilling is in progress, should be brought into an overpressure condition in relation to the well being drilled, and the annular pressure of the wells should be closely monitored.

- Restriction in simultaneous operations during heavy lifts if a sudden loss of suspended loads endanger the safety of other concurrently ongoing operations like such heavy lifts can be, but are not limited to:
  - Handling, running and pulling of BOP, X-mas tree etc. above wellhead areas
  - Running and pulling of risers, drill strings, casings and wellhead components in open water
  - Transfer of heavy equipment between supply boats and rig, etc.
- Activities shall be halted if the gas level in the drilling area exceeds a certain limit set by the operator.
- Special precautions shall be taken when welding, grinding, cutting and other high-energy work in the wellhead, BOP or drillfloor area in parallel with simultaneous activities are performed.

During simultaneous drilling and production, special restrictions shall be implemented for activities that could lead to a reduction of the safety level during drilling through layers containing hydrocarbons.

4.12 Personnel Qualification & Training

In accordance with Statutory regulations and operator procedures, requirements to qualifications or training shall have been set out for all job categories with great impact on safety through the various phases of drilling and well operations. Special training should be provided in the case that new equipment or technology is planned to be used.

4.12.1 Qualifications and Training for Offshore Operations

The following specific qualifications requirements for drilling and well operations personnel are supplemental to the common requirements for offshore personnel regarding such as health certification, basic safety and contingency training with refreshers.

Supervisory personnel shall have training or experience in Norwegian Acts, Regulations and Provisions. Training with respect to work environment factors shall be in accordance with the NPD Regulations relating to systematic follow-up of the working environment.

Personnel involved shall have the education and experience required in compliance with Norwegian Regulations, and shall be able to show proven track records for the same. The OLF/NR’s Recommendations for Training of Drilling Personnel is considered to represent the industry norm. Documented experiences for the specific offshore positions can be provided through an on-the-job-training system compatible with that system recommended or issued by the NR. Requirements to personnel qualifications should also comprise theoretical and practical training when new equipment is introduced. As supplementary standard for personnel qualifications in the area of well service, reference is made to the Education Plan approved by the Norwegian Ministry of Church, Education and Research in respect of Well Service Techniques, detailed within the areas of Wireline Operations and Cementing.

Well Control Training and Refreshers are required for the following offshore positions:

<u>Drilling</u>
Drilling Supervisor, Toolpusher, Tourpusher, Driller, and Assistant Driller.

Well Intervention
Wireline and Coils Tubing personnel are missing under well control training and refreshers requirements.
The following wording is suggested:

The Operator Company's Leader for Well Operations and Intervention. All supervisory personnel for wireline, coiled tubing and snubbing operations, such as: Superintendent, Supervisor and relevant 3rd part equipment suppliers.
Equipment operators that operate the unit, such as: Wireline winch operator, Coiled tubing cabin operator, Snubbing jack operator and Choke operator.

Basic well control training and subsequent refresher courses shall be completed in accordance with US-MMS, UK-HSE or International Well Control Forum (IWCF) certification standards.

The Operator can carry out mandatory control by requesting the Contractors to confirm there is consistence in personnel qualifications requirements by detailed references to existing regulations and standards, and to present any discrepancies and the existing training schedule for personnel involved.

4.13 HSE Management System

Health, safety and environmental protection (HSE) shall receive particular attention through operations planning. An HSE Management system shall be implemented to meet regulatory requirements, and should be compatible with the E&P Forum's «Guidelines for the Development and Application of Health, Safety and Environmental Management Systems». Evidence on shortcomings in HSE performance should result in special measures or support or monitoring as agreed between the Operator and Contractor concerned.

4.13.1 Working Environment & Occupational Health

Work areas should be subject to regular evaluation or charting against the NPD's «Regulations relating to systematic follow-up of the working environment, etc.», NORSOK standard S-002 Working Environment and/or against OLF/NR's «Recommended Guidelines for systematic follow-up of the working environment on Mobile Units, etc.». For operations with mobile units designated for drilling and well operations, the Drilling Contractor can be assigned the role as *Principal Enterprise* according to the OLF/NR's «Standard Agreement concerning Principal Enterprise responsibilities» for co-ordination and follow-up of the working environment onboard. On fixed installations, this role will typically rests with the Operator or Owner. Working environment and occupational health factors with high potential for changes between various wells should receive extra focus, like the changes imposed by the use of chemicals, drilling and completion fluids and additives.

Before start of the operations the workforce shall receive relevant information concerning health hazards related to their work and measures to prevent harmful exposure. Including possible training in correct use of personnel protective equipment and with emphasis on risk and preventative measures associated with non-routine operations, tasks, methods, materials and chemicals.

Systems should be properly implemented for the reporting of accidents, work related diseases, unsafe acts and conditions. A safety delegate system shall be implemented for the drilling and well operations area, and the system shall also include representatives to serve the interests of the Well Service Contractors.

4.13.2 Environmental Protection

Appropriate systems for protection of the environment should be in accordance with the operative parts of the NORSOK S-003 standard for «Environmental Care».

Chemicals, which are discharged to the water or emitted to the air, shall cause as little harm as possible to the environment. Selection of chemicals should be based on an overall evaluation of efficiency, environmental data, safety data and economic criteria. The total evaluation of the product should also address the quantity and concentration of emissions.

All fluids and chemicals (also for emergencies, detergent and thread dope) shall have been tested in accordance with SPCA's guidelines. Chemicals on SPCA's list A and B should be as clean as possible. Chemicals which are included in the Paris Convention's Annex A part I or contain alkylfenol or alkylfenol-connections shall not be discharged.

An assessment of measures for reduced fuel or energy demands and steps to reduce the consumption of chemicals and use of chemicals with better environmental characteristics shall be part of the continuous improvement process. The technology available for reducing discharges to the sea and emissions to the air shall be continuously evaluated.

There shall be systems in place for handling waste and keeping track of chemicals or substances onboard and discharges.

All chemicals used during the course of the work shall have Material Safety Data Sheets conforming to quality requirements issued by the OLF. Data sheets with details about composition, personnel safety data, toxicity, bioaccumulation and biodegradability shall be available for all products.

An inventory of explosives and radioactive materials onboard shall be kept up to date at all times.

The use of thread dope with heavy metal content should be avoided for tubular. The use of heavy metal containing dope should only be used if demanded by technical or safety reasons.

Concerning well testing, other methods than burning shall be considered, including collecting oil. Use of special vessels for collecting oil should be considered, and this evaluation shall be documented.

Effective burning must be provided for, both technically and operationally. Wellbore fluid in the transition between the water or diesel column and the perforations shall not be routed directly over the burners, but may be routed to production or be produced to a storage tank system onboard for subsequent handling.

All discharges shall be recorded and reported via the Operator to the SPCA according to mandatory provisions.

The need for documenting an environmental risk assessment is much dependent of the area or activity in question, and to what extent previous or existing environmental risk analyses can be used. Surface flow tree should be consulted early, if uncertainties exist.

4.14 Safety Drills

Safety drills shall be planned and regularly executed to accomplish for the highest possible awareness.

Drills involving use of blow-out preventers or other well control equipment to handle and unintentional influx of fluid or gas into the well shall be carried out prior to start of operation and further at regular intervals.

Special wells or operations or analyses may result in specific input to type and scope of training and drills. (E.g. for deep water drilling and HPHT wells).

4.15 Reporting to the NPD

In the event of significant alterations of the activity programme, operational interruptions, dangerous incidents and accidents, the operator shall immediately notify the NPD. The Operator shall outline and communicate criteria for such reporting to personnel with dedicated responsibilities for such operation.

During the time that drilling and well activities are in progress, the operator shall on a daily basis keep the NPD informed with regard to the progress of the operations. The NPD and CDRS define the extent of the reporting and reporting routines.

4.16 Experience Transfer

Performance shall be evaluated against the goals set up before commencement of the operations.

Besides the Operators own assessment of performance, and for the purpose of the continuous improvement and transfer of experience, the Contractor is encouraged to advise the Operator of such matters as:

- Challenges in performance versus set goals for the activity.
- Contractor's suggestions for improvements or simplifications in work processes and methods that might contribute to more efficient or cost effective performance by the Operator and his other contractors for future work.
- Information and feedback from circumstances arising during operations, that have reinforced or changed contractors perception of specific subjects, or could lead to a change in contractors relevant documentation, methods or work process.
- Contractor's assessment of deviations from this standard and mandatory requirements, including future recommendations.

4.17 Documentation

4.17.1 Communication or Documentation

In order to ensure proper communication and documentation of planned work performed or to be performed, a structured system for ensuring continuity shall be in place. The system shall include:

- Hand-over reports or meetings at all work levels at crew change and between shifts

- Daily (morning) meetings with offshore and base onshore organisation covering the last 24 hours of operation, accidents or incidents, progress, material requirements and the next actions both at the office and the well site.
- Filing system established onshore and offshore comprising records of:
  - Information on how the operation was carried out, drilling reports, mud reports etc.
  - Documentation of the actual condition of the operation
  - HSE and cost, time, resources, accident or incident reports
  - Non-conformance reports or overview

4.17.2 Operational Reports

Regular operations reports shall be obtained in IADC format, or as agreed with the Operator. Special reports from services executed must be compiled for individual services involved (E.g.: Directional, logs, cementing, drilling fluids)

4.17.3 Post Analyses

Post-activity analyses shall comprise economical, technical, safety and environmental related aspects, and a review report.

A final well report shall be produced after each well, and be submitted to the NPD.

The report's objective is to document results and transfer experience from the performed work.

The final well report shall contain aspects such as, but not limited to:

- Work objective and results
- Conclusions and recommendations
- Well description
- Significant deviations from the original programme, established operational procedures or legislation
- Job review
- Cost breakdown, comparison to planned cost
- Time breakdown and analysis
- Well test or production results
- Other quality parameter analysis

4.17.4 Deviation and Non Conformances

Deviations and non-conformances shall be handled and documented according to statutory regulations and company procedures.

5 OPERATION

5.1 Drilling

5.1.1 Planning

The well design shall be based on the following;

Pore pressure prognosis and formation strengths.

- Expected pore pressure development throughout the planned well trajectory.
- Mud weight required overbalancing the formation pore pressures and maintaining hole stability.
- Expected formation strengths.
- An evaluation of possible overpressures in the well in question based on seismic data and/or experience from neighbouring wells.
- A description of the methods and procedures that will be used to monitor the possibility of encountering an overpressure formation.

Data acquisition.

- Cutting sample collection and description.
- Palynological preparations.
- Logging while drilling.
- Electric wireline logging and logging on pipe.
- Coring intervals.
- Formation side wall samples, formation pore pressure measurements and fluid or gas sample collection.
- Drilling parameters and drilling fluid record.
- Formation production testing.

5.1.1.1 Design Criteria

Casing design.

The casing design shall be such that the strength of both pipe and connection can withstand all pressures and loads that can be expected during the lifetime of the well. The casing design shall take into consideration the following;

- Planned well trajectory.
- Expected pore pressure development.
- Expected formation strengths.
- Expected temperature gradients.
- Induced loads caused by either production testing, long-term production or injection.
- Completion design requirements.
- Potential casing wear.
- Formation evaluation requirements (logging, coring, etc.).
- The potential for H_2S and/or CO_2.
- Final well abandonment using casing cutters and not explosives.
- Hole size to pipe or coupling OD clearance for both running and cementing.
- Induced loads created during workover, killing and stimulation work.

- The conductor pipe or connector to withstand planned top loads, for example the diverter and possible temporary landing off of the surface casing, wave and wind forces and lateral or vertical movements.
- The surface pipe or connection has to support all subsequent loads, for example casing strings, completion or test string and wellhead, BOP etc.
- The isolation of weak formations, potential loss zones, sloughing and caving formations, and protect reservoirs.

Safety factors.
The following minimum design safety factors are generally recommended.

Burst	:	1.1
Collapse	:	1.1 (Based on 60% mudfill)
Tension	:	1.3
Triaxial	:	1.25

It should be noted that tubular connections do not always match the strength of the pipe body. For example, the tensile performance of some connections is described as ‘parting load’, which is generally based on connection design and steel ‘ultimate tensile’ strength. The pipe body tensile performance is based on dimensional cross-section and steel ‘yield’ strength. The basis for connection performance figures should be fully understood before applying the above safety factor, and therefore in some cases a higher factor should be applied.

The compression loading on casing is generally only studied with regard to buckling, however depending upon well design, the surface casing may be subjected to very high compressional loads. The casing connection compressional strength (resistance to thread jump-in) should be considered very carefully particularly non-shouldering type connections.

A detailed casing analysis shall be used to justify the reducing of safety factors.

Casing cementing design.
The cementing programme shall be designed to ensure the casing is supported with complete integrity around the casing shoe to allow the drilling of the next section. Although each casing string is designed for a slightly different function, the principles for cementing apply equally to all.

- All intervals containing moveable hydrocarbons shall be isolated with at least 200 metres of cement above the shallowest zone. If there are no moveable hydrocarbons in the cased interval, then a minimum of 200 metres of cement shall be set above the casing shoe.
- All casing strings and liners which are not to be drilled out, shall have at least 25 metres of cement left inside the string above the casing shoe, and two check valve devices in the shoe track.

Conductor	Shall be cemented back to the seabed with the exception of driven or jetted conductors.
Surface casing	Shall be cemented back to the seabed or inside the conductor shoe.
Intermediate casing	Shall be cemented to at least 200 metres above the shoe, assuming no hydrocarbons.
Production casing	Shall be cemented to at least 200 metres above hydrocarbon interval.
Liners Cemented	Shall be cemented over their entire open hole length and to 100 metres inside the previous casing shoe. If 100 metres of cement are not possible, a liner to casing annulus packer shall be set.
Liners not cemented	For liner sections that do not contain several permeable zones, the cementing requirement can be waived, however an annulus packer shall still be set.

Drilling Fluids Design.
The design of drilling fluid shall be based on requirements relating to well control and drilling efficiency. Special requirements for specific wells shall be identified in the drilling fluid programme.
Personnel safety or working environment and marine environment shall be carefully considered in relation to fluid handling and cuttings disposal.

Environmental considerations make it desirable to control and to limit the use of oil-based drilling fluid. Mineral oil based and synthetic oil based drilling fluids shall only be used when it is absolutely necessary for drilling performance and hole stability. Technical reasons for its use shall be fully documented. General framework conditions shall be drawn up for the use of oil based drilling fluid when the criteria for use are documented. Application for permission to use oil-based mud has to be made at the time of applying for consent to drill and/or produce.
The personnel safety and the environmental impact of using oil-based drilling fluids shall be thoroughly investigated before they are used. Procedures for fluid handling and cuttings disposal shall be documented and made known to all personnel working with such material.
The impact of drilling with oil-based mud on data acquisition, for example formation logging, shall be fully understood before it is used.

Directional Drilling.
The planned well path for all types of wells shall be documented and included in the drilling programme. The well trajectory shall be monitored during drilling and the well bore position relative to other wells known at all times.

Drill string Design.
Drillpipe shall be in accordance with NORSOK standard M-702. In addition, dimensions, drilling torque and tension, hydraulics, make-up torque (MUT) of the tool joint and fatigue factors must be accounted for when selecting the drill string for the well(s) in question. Inspection routines shall be defined in the maintenance programme as agreed upon between Operator and Drilling Contractor.

Drillpipe shall be selected with respect to;

- Make-up torque necessary to avoid down hole make-up.
- Tension and torque capacity when both factors are working simultaneously. A curve showing these factors should be established with due consideration to the effect of fatigue.
- Hole size to pipe and tool joint clearance.
- Internal pressure drops.
- Abrasive formations.
- Buckling.
- Hard banding and its influence on casing wear.
- Elevated temperatures in HPHT wells.

5.1.1.2 Barriers

Where drilling is in progress, the following barrier status will normally exist.

- A barrier consisting of a homogenous mud column with a hydrostatic overbalance on the pore pressure.
- A barrier consisting of a cemented casing, wellhead, pipe ram or annular preventer and drill string with kelly valve or check valve.

Requirements related to barriers:

- Prior to setting the surface casing, it is acceptable to use only the drilling fluid as a barrier in conjunction with a diverter system.
- The barriers shall be designed such that they will prevent or control any unintentional flow from any exposed formation.
- Barriers should preferably be tested from the direction of any potential pressure source. If for example, a cement plug is not to be inflow tested, then it shall be weight tested with either the drill or work string to ten (10) tons and pressure tested from above.
- It is not permitted to intentionally under-balance the formation to release a stuck drill or work string if the well bore fluid constitutes one of the barriers.
- If the drilling fluid is classed as one of the barriers, a riser margin shall be maintained for all drilling operations with the following provisions;
  When drilling in deep water it may not be possible to maintain a riser margin in addition to the other safety margins, such as a trip margin. In this particular case the riser margin should be viewed in conjunction with other barriers in place and procedures to be taken in the event of the loss of the riser. Any deviation from a riser margin requirement shall be highlighted in the drilling programme and reference made to clear and precise procedures to be taken in the event of riser loss. An application for deviation shall be submitted to the NPD.
- If the drilling fluid is classed as one of the barriers, its volume and properties shall be continuously monitored to ensure it is within the programmed specification. Should for any reason the drilling fluid properties deviate beyond the programmed margins, the drilling operation shall be halted until the fluid properties are restored.
- All fluid barriers shall consist of fluid with density to control any pressure in the open hole section and properties to control fluid loss.

Example of barrier elements;

- BOP and it's associated parts.
- Properly cemented casing.
- Cement plugs.
- Casing bridge plugs.
- Wellhead and associated components.
- Mechanical or hydraulic retrievable bridge plugs

5.1.1.3 Well Control

The individual Operator shall develop a well control policy. The operator shall ensure that the drilling contractor has well control equipment and well control procedures that are fully documented, and comply with the operator's well control policy.
The 'Well Control System' shall be in accordance with Norsok Standard, 'Drilling Facilities D-001'.

General requirements.

- There shall at all times be a schematic diagram on the rig floor showing the relevant distances between the rig floor and BOP rams. The space between rams shall also be shown. The driller shall be able to determine the relative position of the drill string tool joint to shear rams at all times.
- Prior to drilling out the surface casing, a blow-out preventer system shall be installed consisting of at least one remote control annular preventer, one shear ram preventer and one pipe ram preventer. The blowout preventer shall be connected to a choke and kill manifold.
- Prior to drilling out of the intermediate casing, production casing and liner, a complete blow-out preventer system (minimum 1 annular + 1 blind shear + 2 pipe rams) shall be installed and connected to the choke and kill manifold.
- The blind shear rams shall be capable of shearing the drill string, work string, tubing, irrespective of grade, and sealing off the well bore. There is no requirement to shear items such as casing, liners, subsea test tree etc.
- During drilling with blowout preventer on the seabed, a diverter system shall be installed. The marine riser shall be fitted with integral choke and kill lines from the blowout preventer stack to the surface choke and kill manifold.
- There shall be sufficient materials or fluids stored on the installation such that 100% of the well fluid volume can be mixed at all times.
- The operator shall establish the additional chemical requirements to be held onboard such that the mud weight can be increased for well control purposes.
- The mixing system's capacity, speed and effect of agitators shall be sufficient to weight up mud in order to keep up with the selected kill rate, once killing has started.
- The mud gas separator system shall be designed to handle the maximum anticipated gas or mudflow rate at kill pump speed.
- The separated gas shall be vented to a safe area, for example four (4) metres above the top of the derrick.
- The flaring of gas is not permitted from a conventional open-ended vent pipe.
- The active pit volume shall be as small as practically possible, with a constant volume measuring device capable of detecting a loss or gain of $0.1m^3$ ('Drilling Facilities D-001' annex B, item 25).

- The trip tank shall have measuring devices capable of detecting a volume loss or gain of $0.05m^3$. There shall be at least two independent systems to monitor the fluid volume into and out of the well, e.g. when the drill string is pulled out. The system shall be designed to compensate for surge caused by the drilling unit heaving.
- Flow checks shall be carried out for a minimum of 10 minutes (15 minutes for HPHT wells).
- Calculations shall be carried out with regard to the surge and swab effect for every trip in wells with high pressure and high temperature sections.
- The fluid return measuring device shall be capable of detecting any change (1% of flow rate, annex B, item 23) in the pre-set return flow rate. In the case of a floating drilling unit, there shall be a system capable of allowing for the heave motion of the unit.
- The return fluid temperature shall be constantly measured during all circulating activities. The instrument shall be capable of detecting changes as small as one (1) degree C.
- The return fluid shall be constantly monitored for gas break out.
- Where there is a potential for casing wear, which will have an influence on the casing design safety factor, some form of wear monitoring or simulation shall be applied, for example ditch magnets and internal casing calliper logging.
- In the case of mobile installations, well securing and disconnection of the riser from the blowout preventer on the seabed shall be possible in the event of an uncontrolled loss of rig position. The total time required to carry out this operation shall take into consideration the riser angle and the environmental conditions. For dynamically positioned installations, well securing and disconnection of the riser shall be possible in the event of a loss of rig position under full power. Procedure for the above shall be documented and personnel shall be trained to carry out these procedures in the event of a crisis.
- In the event of an out of control well (blowout) on an anchored drilling unit, it shall be possible to release individual moorings and pull off location. The system shall be ready for activation at all times without any specific preparation and shall begin to function within 15 seconds after the point of activation. Documented procedures shall be in place covering this critical operation and personnel shall be trained and fully aware of their role in such situations.

<u>Blow-out preventer stack testing</u>

- The blowout preventer stack (BOP) shall be pressure tested to full working pressure either on a test stump or wellhead at least once every six (6) months.
- Intermediate BOP testing shall be to the maximum design test pressure for the casing string onto which the BOP is installed. The blowout preventer shall also be subjected to a low pressure tested.
- Where the BOP has been installed on the sea bed, the test may be limited to the wellhead connection and the kill or choke lines, assuming it has been fully tested on surface to the casing design test pressure. A full BOP function test shall be carried out once it is on the seabed.
- The annular preventers shall be pressure tested to the casing design test pressure provided this does not exceed 70% of its working pressure of the annular preventers.
- Prior to drilling out of casing strings, the BOP shall be pressure tested to maximum design pressure for the relevant well section.
- If the time interval since the last pressure test exceeds fourteen (14) days, the blowout preventer, with exception of the shear or blind ram, shall be pressure tested again even if no new casing string has been installed.

- Function testing of the blowout preventer with kill and choke lines valves shall be performed weekly. Function testing shall be carried out with alternate systems or panels. If the blowout preventer is located on the seabed, this will also include function testing of the acoustic system.
- The test pressure shall be kept stable for at least 10 minutes at high pressure, and at least 5 minutes at low pressure.
- The surface equipment (standpipe and choke & kill manifold) shall also be tested in conjunction with the BOP testing.
- All pressure testing shall be fully documented.
- A complete overhaul and testing of blowout preventer shall be carried out every five (5) years. Refer to API Specification 6A and API RP 53 or equivalent recognised standard. The complete overhaul shall be documented.

Shallow gas
Well locations shall be selected where the risk associated with shallow gas is lowest. Shallow gas risk shall be assessed for all locations based on area knowledge and seismic surveys.
Depending upon the probability of encountering shallow gas or drilling into a charged formation before the BOP stack is installed, a pilot hole (of 9 7/8” or equivalent) shall be drilled and the well data evaluated before a further opening of the well to the required diameter.

If no pilot hole is planned at a location with water depth less than 100 meters, the operator shall carry out a consequential analysis for the drilling installation with respect to shallow gas influx.

Drilling a pilot top-hole with a riser or conductor installed, the hole size shall be small enough to limit or prevent an influx into the well bore by use of the dynamic pressure drop in the annulus whilst circulating with drilling fluid. Any influx occurring whilst circulation has stopped would be control by re-establishing circulation at a high rate and then pumping kill mud.

In top-hole sections with potentially different pressure regimes, which may cause an influx or communication between the zones, the following shall be carried out;
- Drill with mud to overbalance all pressure regimes.
- Drill with a diverter system (not applicable when drilling riserless).
- Penetration rate for drilling the pilot holes shall be restricted to allow for MWD/LWD data acquisition, thus gas detection.

During the drilling of the top-hole section from mobile facilities, there shall be an ROV deployed at the wellhead to continually observe the seabed.

There shall also be sufficient weighed mud onboard ready to pump should the well start to flow.

The diverter element installed shall be capable of closing around all sizes of pipe run into the well.

The diverter system shall be operable irrespective of wind direction, this is normally achieved with two pipes leading out to opposite sides of the installation. If only one diverter line is available, restrictive drilling practices will apply governed by the weather conditions.
The design of a diverter system shall minimise the total friction loss in the system.
Emergency release of the riser from the conductor or wellhead shall be possible from an additional control panel placed in a safe area.

Training & reporting

- All relevant supervisory drilling staff shall be fully trained and qualified in well control procedures.
- For each drilling crew, pit level drills should be carried out at least twice per week to ensure the drilling crews are familiar with the action to be taken in the event of a pit level variation.
- Drills involving the use of blowout preventers to prevent an influx of fluid or gas into the well during drilling shall be carried out weekly for each crew.
- When conditions permit, drills should be carried out as realistically as possible with fixed pressure build-up, preparation, start of circulation and choke adjustment etc.
- Drills should be repeated with sufficient frequency to achieve an acceptable reaction time.
- Drills carried out shall be recorded in the daily operations report and IADC report.

5.1.2 Plugging & Abandonment

5.1.2.1 General

A plugging and abandonment programme shall be prepared and submitted to the NPD at least one week prior to the commencement of activities.
The well shall be secured by means of two barriers in line with the requirements listed under 'Barriers' above. The abandonment shall entail the securing of all annular spaces between casings, all casing cuts, the shoe of the deepest set casing and all perforations.
The barriers may be a combination of any two (2) of the following, with at least one (1) barrier consisting of cement.

- The primary cementation.
- Squeeze cementation.
- Cement plugs.
- Mechanical packer.
- Mechanical bridge plug.
- Thermo-set resin.

All perforations shall be isolated by means of a squeeze cementation or thermo-set resin, and a mechanical barrier.

In general, barriers shall be pressure tested to 70 bar above expected formation strength below shoe of the deepest casing string. However, the test pressure shall not exceed previous casing test pressure.

Cement plugs placed in the transition zone between open hole and casing shall be subjected to a mechanical load of at least 10 tons.

5.1.2.2 Permanent plugging and abandonment

The well shall be plugged according to a separate plug and abandonment programme in such a way that the general requirements in section **5.1.2** are fulfilled.

5.1.2.3 Plugging of open hole

Cement plugs with minimum length of 100 m shall be set to isolate permeable zones in open hole. Cement plugs shall extend minimum 50 m from the top of the permeable zone and upwards, or 50 m from the potential flow point and upwards.

A barrier shall be placed in the transition zone between open hole and casing. The barrier can be either a mechanical packer or a cement plug, extending for a minimum of 50 m above and below the casing shoe.

5.1.2.4 Plugging of perforations

Prior to installing a squeeze retainer an injection rate through perforations shall be established. If injection is obtained, all perforated zones shall be isolated with a mechanical plug and squeeze cemented.

If the injection rate cannot be obtained, a cement plug shall be set across perforations extending a minimum of 100 m above the top perforations. If the distance between the test intervals is less than 100 m thus making a 100 m cement plug impossible, a mechanical packer should be set as close to the top of the perforations as possible.
Minimum of 10m cement shall be left on top of the squeeze retainer.

5.1.2.5 Plugging of liner laps

A cement plug shall stretch for a minimum of 50 m above and below the liner top.

5.1.2.6 Cut and pull of casings

Each casing shall be cut at sufficient depth to fulfil all barrier requirements.

Cutting the casing, perforating casings and retrieving seal assemblies shall be performed under complete pressure control to relieve overpressures in annulus between casings.

A float valve shall be used in the BHA during cutting operation.

To enable circulation when pulling on cut casings, a spear with pack-off or casing-landing string shall be used.

Explosives are not permitted used for cutting the casing string to remove the wellhead. Only in exceptional cases and several unsuccessful attempts with mechanical cutters, can the use of explosives be accepted. The use of explosives shall in such cases be handled as a deviation from the NPD regulations.

The wellhead and the following casings shall be removed so that the top cut is minimum 5 m below seabed.

5.1.2.7 Plugging above cut casings

Potential flow sources behind the casing strings shall be located and plugged with a minimum of two barriers to secure all annular spaces and casing cuts. At least one of these shall be a cement barrier.

The minimum height of a cement plug shall be 100 m. Cement plugs shall extend minimum 50 m from the top of a permeable zone and upwards, or 50 m from a potential flow point and upwards.

Requirements related to minimum height and length are not applicable to the plugging of conductor casing and/or surface casings cemented to the seabed.

5.1.2.8 Surface plug

The surface cement plug shall be minimum 200 m in length and the top of the cement shall run no deeper than 50 m below the seabed.

5.1.2.9 Inspection of the drill site area after a plug back operation

The inspection shall cover an area around the drill site, which as a minimum corresponds to the operational area for the cranes on the drilling installation. The inspection shall be documented. The documentation could be videotape with position indications and an overtrawling report.

5.1.2.10 Temporary abandonment

5.1.2.10.1 Plugging of open hole

Wells with an open hole section cannot be plugged temporarily, except for a shorter period of time where problems have occurred in the well like pulling of the BOP due to leakage, functional problems etc.

If any hydrocarbon bearing zones or permeable zones with different pressure regimes have been drilled through, a cement plug of minimum 100 m must be set. The cement plug shall extend for a minimum of 50 m from the top of the permeable zone and upwards, or 50 m from the potential flow point and upwards.

If no hydrocarbon bearing zones have been drilled through or HC zones have been isolated, a cement plug or mechanical packer shall be installed at the bottom of the casing. When this is a cement plug, it shall be minimum 100m.

In addition, another cement plug or mechanical packer shall be installed as deep down as possible. If this is cement, it shall be minimum 100m.

5.1.2.10.2 Plugging of a perforated casing or liner

A cement plug or a mechanical packer shall be installed immediately above the top of the perforations. If this is a cement plug, it shall be minimum 100 m, without covering the liner lap.

In addition, another cement plug or mechanical packer shall be installed as deep down as possible. If this is a cement plug, it shall be minimum 100 m. If a liner is set this cement plug or mechanical packer shall be placed approximately 100 m above the suspension point of the liner.

5.1.2.10.3 Plugging when last casing has full integrity

In wells where the last casing string is not perforated, drilled out or where a cement plug or a mechanical packer at the bottom seals off the casing, the well shall be secured with an additional barrier.

The barrier can be either a 100 m cement plug or a mechanical packer. The barrier shall be placed as deep down as possible. If the barrier is a mechanical packer it can be of the retrievable type.

If no hydrocarbon bearing zones have been penetrated, drilling fluid including riser margin may constitute one of the barriers for a shorter period of time. This shall be handled as a deviation from the NPD regulations.

5.1.2.10.4 Covering of wellhead

A protection structure with corrosion cap shall be placed over the wellhead structure prior to temporary abandonment.

5.2 Completion or workover

5.2.1 Planning

An approved completion or workover activity programme shall be submitted to the NPD minimum 1 week before starting the activity. The completion or workover programme shall contain all required well specific information for performing the activity.

5.2.1.1 Design Criteria for Completion or Workover Tubing

Strength requirements for the tubing shall be evaluated to determine the appropriate material grade, wall thickness and threaded connection design. Material selected shall be resistant to corrosion to a degree that eliminates corrosion as failure mechanism during lifetime of the well. Tubing size or wall thickness shall be dimensioned for production or injection not to exceed the erosion velocity for the tubing at max production or injection.
Threaded connection design shall be determined upon application of the tubing.

The minimum allowable design factors (DF) shall apply:
(DF = Specified tubing strength or Actual stress from loadcase)

- Burst: 1,1
- Collapse: 1,1
- Axial, static (pipe body and connection whichever combination is weaker): 1,3
- Triaxial yield: 1,3
- Running and installation loads, including pressure testing: 1,35

Completion or Workover tubing shall be designed on the basis of realistic installation and pressure test scenarios, steady state and worst-case scenarios.

The design shall include both actual situations and all future options intended for that particular tubing string or well.

Design shall be done on the basis of input from below listed parameters. However if any additional parameters occur due to any special application of the tubing, they shall also be included:

- Reservoir data
- Well data
- Production or Injection data
- Fluid data
- Well control contingencies
- Interface or Compatibility
- Well Intervention and treatment

Reputable well design software should be applied for evaluation and verification of the completion tubing design.

Approved well design software should be applied for verifying the completion string design. The string shall be designed for all the potential load cases including future planned use of the actual well.

5.2.1.2 Barriers

Long term planning for possible future stimulation and/or injection should be considered with special emphasis on temperature and pressure. The normal barrier status for a production well shall be:

- One barrier consisting of a cemented casing, packer, production tubing and down hole safety valve
- One barrier consisting of a cemented casing, wellhead and X-mas tree with associated valves

In addition to the barrier philosophy outlined in chapter 4.5 Barrier Philosophy, the following shall be included in the completion or workover activity programmes:

- All components in the completion string shall have gas tight premium connections.
- The SCSSV shall be placed at a safe depth and at least 50 meters below the seabed, and shall be of fail safe closed type and controlled from the surface.
- The tubing hanger shall provide suspension of the entire completion string and provide an annular seal.
- An annular barrier element shall be installed if the annulus is to be used for gas lift. On fixed installation an annulus barrier element shall be installed.
- Continuous monitoring: The production annulus shall be monitored for pressure during the production phase.
- Pressure monitoring of B-annulus in gas lift wells.
- Barrier requirements to annulus injection or production wells.

5.2.1.2.1 Barrier Testing, Status and Availability

The most typical barrier elements are listed in the table presented in attachment 5.2. This table should be filled in with the actual barrier elements and their definition of being part of Primary or Secondary barrier. Furthermore the table should be filled in to describe testing status and availability features for the individual barrier elements.

The presented table is a suggested format, other formats serving the informative purpose might be used.

5.2.1.2.2 Failure Criteria

Particular emphasis shall be placed on the following scenarios:

- Inflow or fluid loss while running or pulling completion string
- Tubing leak
- Running non shareable items across BOP shear rams
- Imminent disconnect

5.2.2 Operations (including Equipment Rig-up and Testing or Demobilisation)

For both completion and workover operations, a detailed description of the planned tasks to be executed shall be included in an operation programme prepared for the specific operation.

5.2.2.1 General Requirements

A pre-operation meeting shall be conducted at a convenient time prior to commencing a new well work-programme in order to familiarise key staff and suppliers in the operation of the planned programme.
Operation manuals shall be available covering all aspects of significance to safety, including procedures, organisational matters, areas of responsibility etc.

5.2.2.2 Equipment Rig-up

Proper, formal interface with the rig systems for the offshore facilities must be established. Norsok Standard Z-015 on Temporary Equipment is considered as recognised standard in this context.

5.3 Testing

5.3.1 Planning

The preliminary planning of a possible well test shall as a minimum involve the following steps:

- Objectives and estimated activity time schedule.
- Reservoir information.
- Establishment of project responsible persons.
- Functional requirements of equipment based on objectives and reservoir information.
- Equipment selection.
- Detailed string design
- Risk assessment for testing operation and test equipment
- Equipment verification through Contractor’s (Company approved) testing procedures and quality control system prior to being shipped offshore.
- Logistics
- Equipment rig-up

The NORSOK standard D-SR-007 System requirements: Well Testing systems, should be referenced.

Requirements towards authorities:
SPCA: Notification 14 days and 2 days prior to test.
Approval for eventual planned discharge to be in place.
NPD: Consent to test, normally given as part of drilling consent.
Application to test.
Documentation requirements:

- Well test planning procedures with minimum design factor requirements
- Equipment check out procedures
- Well test programme
- Logistics plan
- Third party certification on surface well testing system
- Contingency procedures where applicable
- Contractor documentation: Operating procedures and equipment drawings, API process review, safety analysis, etc.

5.3.1.1 Design Criteria

The selection of well testing operational methods and procedures and of well testing equipment shall be determined by considerations of operational efficiency, cost effectiveness, safety and risk to the environment. The well test operations programme shall define and specify limitations, well barriers and optimal solutions for the specific well based on the well design. Parameters taken into account when designing a well test and establishing a well test operations programme shall include, but not be limited to:

- Tubing design (incl. design factors as Burst, Collapse and Tri-axial stress)
- Casing design (incl. design factors as Burst, Collapse and Tri-axial stress)
- Bottom hole temperature and pressure
- Surface flowing temperature and pressure
- Shut in well head pressure
- Flow rates
- Seabed depth
- H_2S or CO_2 concentration
- Sand production
- Water cut
- Heavy viscous crude's
- Separation problems or foaming
- Hydrate formation
- Wax or asphaltenes

5.3.1.2 Barriers

Normally the two independent barriers for a floater are composed as follows.

Primary barrier:	Liner or casing through reservoir, test packer, tubing string, Sub Sea Test Tree & landing string, surface tree.
Secondary barrier	Liner down to test packer, casing, wellhead, BOP.

In the case where wireline is rigged up, additional lubricator valves and surface wireline BOP with stuffing box should be installed on top of the surface tree as additional barrier elements to the primary barrier.

To ensure well control at all times during testing, the following should be ensured prior to bringing the well on stream:

- All defined barrier elements and surface test system shall be tested and verified according to plan.
- The SSTT should be positioned such that the shear ram can be closed, shearing the landing string and sealing the well.
- The kill side of the surface test tree shall be hooked up and manifold such to allow pumping into the string using a high pressure (cement) pump, or taking returns to the rig choke manifold and mud or gas separator.
- During flowing and shut in period's annulus pressure and trip tank level should be monitored on a regular basis.
- The Annulus shall be lined up to a choke manifold to enable the following:
- Pressurisation of the annulus.
- Pumping into the annulus for reverse circulating.
- Monitoring annulus pressure.

- Bleeding off excess pressure into trip-tank.
- Internal Blow-out Preventers (IBOP's or kelly kocks) shall be available to be installed during running and pulling of the test string. (with proper Cross Owers).
- The PSD/ESD system shall be function tested.

For the following operations plans shall be in place including equipment availability and operability.

- Killing of the well
- Preventing of hydrates
- Personnel safety in the event of poisonous gas in the well stream

5.3.1.2.1 Barrier Testing, Status and Availability

The most typical barrier elements are listed in the table presented in attachment 5.3. This table should be filled in with the actual barrier elements and their definition of being part of Primary or Secondary barrier. Furthermore the table should be filled in to describe testing status and availability features for the individual barrier elements.

The presented table is a suggested format, other format serving the informative purpose might be used.

5.3.1.2.2 Well Control

Particular emphasis shall be placed on the following scenarios:

- Inflow or fluid loss while running or pulling test string
- Tubing leak
- Subsea Tree disconnect

5.3.1.3 Operations (including Equipment Rig-up and Testing or Demobilisation)

Pre-test meeting onshore

A pre-test meeting shall be held prior to mobilisation of equipment for the well test. Representatives from the service companies involved in the well test should attend the pre-test meeting.

Pre-test meetings offshore

An offshore pre-test meeting shall be held with all personnel associated with the well test onboard.
A pre-flow meeting shall be held prior to opening the well for the first time.
The results from the risk analyses should be discussed with the involved offshore personnel.

Personnel

The operator shall stipulate personnel requirements regarding qualifications and experience for the position (Ref. OLF 024) and the duties and responsibilities for well testing personnel. Offshore a thorough hand over, including present operational status, operational problems and present plans, at change of shift shall be carried out to ensure an ongoing safe and efficient operation.

Leak and Pressure Testing

The following basic principles and requirements for testing the well control system and barrier elements shall be used and documented:

- All well control and test process equipment that may be exposed to well fluids or pressure shall be included in the pressure test or leak test programme.
- All tests shall be performed in the normal direction of flow to the extent possible.

- All pressure and leak testing shall be documented by pressure recording chart. The chart and the test documentation shall clearly indicate type of test, test limit, system or components tested and time & date for the test.

Execution of the work programme
The Company approved work programme and checklists, if used, shall be followed on a documented step by step basis, any deviations from the work programme shall be handled according to Company procedures.

5.4 Well Intervention

This chapter describes the minimum requirements for snubbing, coiled tubing and wireline or tractor operations regarding planning, execution, organisation and documentation.

Evaluations regarding whether the operation shall be carried out in such manner as to require a risk analysis prior to commencing the operation shall be decided in each separate case. Risk analysis shall be performed in the event of deviation from approved programmes or procedures. Acceptable methods for evaluating risk like, "Safe Job Analysis" (SJA) and/or HAZOP studies shall be used.

Prior to commencing a well intervention operation, a pre-job meeting shall be conducted on the installation. Company representative(s), contractor responsible representative(s), other involved contractors and crane operator shall attend this meeting.

The pre-job meeting shall cover the work programme including:

- Objective(s) and estimated activity time schedule
- Organisation of the work
- Lines of responsibility and communication during normal operations and in emergency situations
- Summary of potential technical and operational problems that may occur with reference to planned measures and procedures to be followed in such events
- Safety aspects
- Equipment rig-up
- Discussion of main findings from risk analyses
- Need for SJA

5.4.1 Design Criteria

The choice of well intervention equipment or method shall be based on cost or safety or operations or well data considerations. The operations programme shall define and specify limitations, well barriers, reporting lines, responsibility and safety matters, to ensure optimal solutions for the specific well based on well design.

5.4.2 Barrier

5.4.2.1 Barrier Testing, Status and Availability

The most typical barrier elements are listed in the table presented in the referenced attachments. This table should be filled in with the actual barrier elements and their definition of being part of

Primary or Secondary barrier. Furthermore the table should be filled in to describe testing status and availability features for the individual barrier elements.

Snubbing - Attachment 5.4.1
Coiled Tubing - Attachment 5.4.2
Wireline or Tractor - Attachment 5.4.3
The presented tables is a suggested format, other format serving the informative purpose might be used.

5.4.2.2 Technical Considerations

5.4.2.2.1 Snubbing
The typical well control rig-up for a snubbing operation consists of from top:

- Stripper rubber
- Annular
- Stripping rams
- Upper Pipe ram
- Shear or seal ram
- Lower Pipe ram
- Safety Head (Shear or seal type ram)
- X-mas tree with connected kill line on TKV.

5.4.2.2.2 Coiled Tubing
A typical required well control rig-up for a Coiled tubing (CT) operation on a fixed installation (including TLP's) consists of from top:

- Dual strippers with rubbers and bushings for intended size of CT.
- The CT BOP shall have a kill port between the shear or seal ram and the pipe ram.
- Shear or seal ram (Safety head) with independent hydraulic- (accumulators) and control system.
- X-mas tree with connected kill line on TKV.

A typical required well control rig-up for a Coiled tubing operation on a floater consist of from top:

- Dual strippers with rubbers and bushings for intended size of CT.
- Triple CT BOP dressed with (from top): shear ram, pipe ram and slip ram.
- Triple CT BOP dressed with (from top): shear or seal ram, pipe ram and slip ram.
- Surface flow tree with connected kill hose.
- High-pressure riser terminated in the subsea barrier element (SSTT or LRP). If using a SSTT this shall be spaced out inside the drilling BOP so that the high-pressure riser can be disconnected or cut. The drilling BOP will then be the second barrier.

5.4.2.2.3 Wireline or Tractor
A typical well control rig-up for a Wireline or Tractor operation consists of from top:

Slick line:

- Stuffing box including a blowout plug or a ball check valve (for live well intervention)
- Tool catcher
- Lubricator
- Cable ram (maintaining pressure from below)
- Shear seal ram (independent hydraulic operated for live well intervention)

Braided line or Electric line:

- Grease injection head including integral ball check valve and min. 3 ea flow tubes
- Tool catcher
- Lubricator
- Cable ram (maintaining pressure from below)
- Cable ram (maintaining pressure from above)
- Shear seal ram (independent hydraulic operated for live well intervention)

Connections for injecting grease between the BOPs cable rams shall be present.

A double valved kill inlet connection shall be included in the rig-up, during a live well intervention. The use of braided- or electric line and tractor requirement up to 10 amperes negative earth on outer armour, shall be handled as a deviation from the NPD regulations.

5.4.3 Operations (including Equipment Rig-up and Testing or Demobilisation)

5.4.3.1 Company work programme

The Company produced and approved work programme shall be the basis for performing the work.

5.4.3.2 Check lists

A system with checklists should be established in order to perform a systematic and documented operation. Contractor and company representatives should sign the checklists.

5.4.3.3 Equipment reception control

Contractor shall inspect equipment received on the installation. The equipment shall be placed and safety marked or fenced according to Company requirements.

5.4.3.4 Testing of well control equipment

The following basic principles and requirements for testing the well control system and barrier elements shall be used and documented:

- All well control and connected equipment that may be exposed to well fluids or pressure shall be included in the leak test programme.
- A low-pressure leak test shall be performed prior to a high-pressure leak test.
- All tests shall be performed in the normal direction of flow.
- As a minimum, the two valves closest to the wellbore shall be included in the leak test programme.

Leak test requirements:

Testing against any valve on X-mas tree or Lubricator Valve shall be cleared and executed according to procedures on the installation.

The contractor shall document all tests related to his equipment.

All pressure- and leak testing shall be documented by pressure recording chart. The chart and the test documentation shall clearly indicate type of test, test limit, system or components tested and time & date for the test.

The pressure recorders utilised shall have corresponding calibration certificate documentation.

If there is a risk of hydrate formation, ensure that the fluid pumped or dropped into the well will not form hydrates when contacting the well fluid or gas.

5.5 Pressure Controlled Drilling

5.5.1 Introduction

Pressure controlled drilling is defined as the process of penetrating new formation with the wellbore pressure intentionally designed to be lower than the formation pressure. Consequently, the hydrostatic pressure exerted by the drilling medium will no longer be the primary well control mechanism and shall be handled as a deviation from the NPD regulations.

5.5.2 Scope

This chapter describes the minimum requirements for pressure controlled drilling operations with both jointed and continuous pipe (coiled tubing).

PCD utilising CT or snubbing shall be in accordance with NORSOK standards D-SR-005 and D-SR-006 respectively, hence for these cases this standard contains additional requirements specific for UBD.

5.5.3 Goal

The goal of PCD is to reduce formation damage and/or improve drilling performance while maintaining a high level of safety.

Potential advantages of PCD:

- reduce or eliminate productivity impairment (formation damage)
- improved rate of penetration
- eliminate potentially environmental hazardous drilling and completion fluids
- reduce drilling problems such as; differential sticking, lost circulation in depleted zones, reduced ECD’s
- indications of productive zones while drilling
- potential cost savings (e.g. drilling fluids)

5.5.4 Risk Analyses

Risk analysis is particularly important for PCD operations for the following reasons:

Pressure controlled drilling is a relatively new type of operation on the Norwegian continental shelf.

As opposed to conventional drilling operations, return of pressurised and potentially combustible fluids and gases to surface is common in PCD operations.

A risk analysis shall be performed for each location where PCD operations are planned. For subsequent operations at the same location a new risk analysis shall be performed if critical process parameters have changed.

The following elements shall as a minimum be considered:

- reservoir fluid type and properties
- surface pressures and temperatures
- fluid type, circulating pressure and rate
- well effluent handling requirement
- erosion of surface equipment
- gas level in returns
- no H_2S in returns
- density, stability and type of kill fluid
- kill method and fluid availability
- interaction with platform production system (e.g. ESD systems, production upsets)
- well control scenarios
- emergency preparedness for environmental spill
- barrier philosophy or well control actions

Values for maximum surface pressure, temperature and gas level shall be defined through the risk analysis.

Detailed contingency procedures shall describe the actions to be taken in case any of these values are exceeded during the operation.

5.5.5 Planning & Design

The following issues shall be considered during the planning and design phase of pressure controlled drilling operations:

- The integrity of the wellhead and casing or tubing in case of pressure controlled drilling operations in an existing well.

- Method of achieving underbalances (e.g. gas injection techniques)

- Downhole monitoring system for pressure, temperature and flow rates

- Closed returns handling system for solids removal and fluid and gas separation

- In conjunction with the selection of drilling medium, the following factors shall be considered:
  - required wellbore pressure
  - bit (BHA) cooling
  - hole cleaning properties

  - reservoir compatibility
  - corrosion and erosion issues
  - surface separation and emulsion or foaming tendencies
- Thorough flow modelling, particularly with multiple phase flow, is critical in order to estimate downhole pressure, model cutting transport, gas or liquid ratio’s, injection pressure, operational window for motors or turbines, optimum underbalance pressure, and to determine flow contribution from subsurface zones. Dynamic multiphase flow models should be utilised

- In case gas or foam is utilised, the acquisition of various drilling parameters (e.g. pressure fluctuations, gas analysis) as well as some electric logs could be affected and pulse telemetry systems (MWD equipment) may not work.

- BHA design

- Hole stability

- When designing casing or tubing, specific cases reflecting the loads imposed by underbalanced operations should be included.

- The installation of a temporary casing string (parasite casing) to reduce wellbore volume and casing wear and improve hole cleaning

- Interface with installation facilities (risk of production upsets)

- Due to the complexity of and the amount of equipment needed for pressure controlled drilling, the following HSE issues shall be defined:
  - escape routes
  - zone classifications
  - working environment for personnel (Regulation relating to systematic follow-up of the working environment)

5.5.6 Barriers & Well Control Equipment

From a barrier point of view the main difference between u pressure controlled drilling and conventional drilling operations is that the drilling medium does not provide a higher hydrostatic pressure than the formation pressure and consequently is not a barrier.

During pressure controlled drilling operations, the drilling medium shall be contained in a closed system. The following well control equipment shall be used when drilling pressure controlled:

- Safety Head (shear or seal) with an independent closing unit as close as possible to the wellhead
- A minimum of two-tested backpressure valves (BPV) in BHA
- Strippers or rotating diverter with separate independent power system
- BOP with three independent rams, shear or blind, slip and pipe
- Annular BOP
- A minimum of two flanged flow line valves with metal to metal seal, one manual and one hydraulic valve as close as possible to the BOP stack
- When using jointed pipe, a kelly cock shall be available at all times in case of BPV failure

In this document barrier requirements for pressure controlled drilling operations will be separated into two different scenarios:

1. Pressure controlled drilling through production tubing.
2. Pressure controlled drilling with no production tubing

Below are listed elements of primary and secondary barrier for these scenarios.

Elements of Primary and Secondary barrier:

Scenario	Primary Barrier	Secondary Barrier
1	BHA BPV's	
	Pipe or CT	
	Rotating Diverter or Stripper Rubber	
	Flow Line	
	Choke	
	Flow line gate valve housing	
	Risers	
	BOP stack housing	Safety Head
	Safety Head housing	Safety Head housing
	X-mas tree housing	X-mas tree housing
	Prod. kill or wing valve	Well head
	Tubing hanger	Production casing hanger
	Production tubing	Cemented production casing
	Production packer	
	Cemented casing or liner below production packer	
2	BHA BPV's	
	Pipe or CT	
	Rotating Diverter or Stripper Rubber	
	Flow Line	
	Choke	
	Flow line gate valve housing	
	Risers	
	BOP stack housing	Safety Head
	Safety Head housing	Safety Head housing
	Casing hanger	Casing hanger
	Last cemented casing	Last cemented casing

The primary and secondary barriers are not independent of each other for any of the scenarios. For through tubing drilling, elements in common are Safety Head and X-mas tree housing. In case of drilling with no tubing present, elements in common are Safety Head housing, Casing Hanger and last cemented casing.
Due to this dependence, compensating measures shall be implemented.

Kill fluid shall be available onboard and lined up to the well below BOP and Safety Head. It shall be possible to kill the well at all times independently of the drilling medium, choke manifold, and flowline. Type of fluid shall be defined in the risk analysis performed prior to the operation.

The Safety Head, BOP arrangement, rig choke manifold and choke or kill lines shall only be used for well control purposes.

For the scenarios with no tubing present, the degree of dependence is much higher than for through tubing drilling. For such operations the operator shall implement additional compensating measures and through a separate risk analysis show that the level of safety to personnel, equipment and environment is acceptable.

5.5.7 Equipment Requirements

For all pressure controlled drilling operations the following operational equipment shall be used:

- Bottom hole temperature and pressure monitoring equipment
- Equipment for gas level monitoring in drilling medium return
- A minimum of two-flow control valves (choke valves) due to possible erosion
- A system for handling pipe or tubing in light condition (snubbing jack, CT injector)
- A closed separator system with pressure or temperature monitoring and oxygen or hydrocarbon level sample point
- ESD system
- Drilling medium data acquisition equipment

The following operational equipment shall be considered for use:

- Nitrogen generation equipment
- Gas injection system
- Chemical injection system (glycol, foam breakers, etc.)
- Burner boom and manifold
- Solids control equipment (strainer, cyclone, sand separator)

5.5.8 Operations

Prior to any pressure controlled drilling operation it is important to verify that simultaneous operations and contingency procedures have been written and are valid for the actual location. Supervising personnel shall have experience with both drilling and live well intervention. Training or experience of all personnel shall be documented.

The following issues shall be highlighted during a pressure controlled drilling operation:

- The driller shall operate the choke.

- When a BPV or float sub is pulled out of hole, special procedures shall be followed to safely remove trapped pressure.

- There shall be installed a WHP readout at the driller's station.

- The safety head shall only be used for emergency situations.
- It shall always be possible to kill the well from below the safety head.

- The kelly cock available at the driller's station shall hold pressure from both directions.

ATTACHMENT 5.2 BARRIER TESTING, STATUS AND AVAILABILITY FOR WELL COMPLETION OPERATIONS (INFORMATIVE)

		Testing			Status	**Availability**			
	Barrier Element	**Test method**	**Test Duration**	**Test Frequency**	**Monitoring**	**Engagement**	**Response**	**Alternative Barrier**	**Comments**
Example	Production Liner	Applied pressure from within the well	10 minutes	At installation	Fluid balance in well	Active	None (or kick control)	Fluid Column	This is an example on how the table can be filled in
Primary Barrier	Production Liner								
	Liner Lap								
	Fluid Column								
Secondary Barrier	Casing and Cement								
	Casing Hanger w/seals								
	Wellhead								
	Wellhead Connector								
	High Pressure Riser								
	BOP Body								
	Shear Ram								

ATTACHMENT 5.3 BARRIER TESTING, STATUS AND AVAILABILITY FOR WELL TESTING OPERATIONS (INFORMATIVE)

		Testing			Status	Availability			
	Barrier Element	**Test method**	**Test Duration**	**Test Frequency**	**Monitoring**	**Engagement**	**Response**	**Alternative Barrier**	**Comments**
Example	Production Liner	Applied pressure from within the well	10 minutes	At installation	Fluid balance in well	Active	None (or kick control)	Fluid Column	This is an example on how the table can be filled in
Primary barrier	Production Liner								
	Liner Lap								
	Fluid Column								
	Packer								
	Downhole Tester Valve								
	Subsea Test Tree								
	Body of Lubricator valve								
	Surface Test Tree								
	Tubing								
Secondary barrier	Casing and Cement								
	Casing Hanger w/seals								
	Wellhead								
	Wellhead Connector								
	BOP Body								
	Shear Ram								

ATTACHMENT 5.4.1 BARRIER TESTING, STATUS AND AVAILABILITY FOR SNUBBING OPERATIONS (INFORMATIVE)

		Testing			Status	Availability			
	Barrier Element	**Test method**	**Test Duration**	**Test Frequency**	**Monitoring**	**Engagement**	**Response**	**Alternative Barrier**	**Comments**
Example	Production Liner	Applied pressure from within the well	10 minutes	At installation	Fluid balance in well	Active	None (or kick control)	Fluid Column	This is an example on how the table can be filled in
Primary barrier	Snubbing stripper								
	Snubbing pipe body								
	Back Pressure Valves								
	Snubbing BOP								
	Riser								
	Safety head housing								
	X-mas tree								
	Tubing hanger								
	Tubing								
	Test or Prod. Packer								
	Casing or liner through reservoir								
Secondary barrier	Safety head housing								
	Safety head								
	X-mas tree								
	Nipple profile in BHA								
	Well head								
	Prod. casing hanger								
	Production Casing								

ATTACHMENT 5.4.2 BARRIER TESTING, STATUS AND AVAILABILITY FOR COILED TUBING OPERATIONS (INFORMATIVE)

		Testing			Status	Availability			
	Barrier Element	**Test method**	**Test Duration**	**Test Frequency**	**Monitoring**	**Engagement**	**Response**	**Alternative Barrier**	**Comments**
Example	Production Liner	Applied pressure from within the well	10 minutes	At installation	Fluid balance in well	Active	None (or kick control)	Fluid Column	This is an example on how the table can be filled in
Primary barrier	CT dual stripper system								
	CT body								
	CT check valves								
	CT BOP								
	Riser								
	Safety head housing								
	X-mas tree								
	Surface Flow Tree								
	LRP housing								
	SSTT								
	Subsea X-mas tree								
	Tubing hanger								
	Tubing								
	Test or Prod. packer								
	Casing or liner through reservoir								
Secondary barrier	Safety head housing								
	Safety head								
	X-mas tree								
	LRP shear or seal ram								
	Subsea drilling BOP								
	Subsea drilling BOP shear or seal ram								
	Subsea X-mas tree								
	Well head								
	Production Casing hanger								
	Production Casing								

ATTACHMENT 5.4.3 BARRIER TESTING, STATUS AND AVAILABILITY FOR WIRELINE OR TRACTOR OPERATIONS (INFORMATIVE)

		Testing			Status	Availability			
	Barrier Element	**Test method**	**Test Duration**	**Test Frequency**	**Monitoring**	**Engagement**	**Response**	**Alternative Barrier**	**Comments**
Example	Production Liner	Applied pressure from within the well	10 minutes	At installation	Fluid balance in well	Active	None (or kick control)	Fluid Column	This is an example on how the table can be filled in
Primary barrier	Stuffing box or Grease injection head								
	Lubricator								
	WL BOP								
	Riser								
	Safety head housing								
	Surface Flow Tree								
	LRP housing								
	SSTT								
	Subsea X-mas tree								
	Tubing hanger								
	Tubing								
	Test or Prod. Packer								
	Casing or liner through reservoir								
Secondary barrier	Safety head housing								
	Safety head shear or seal ram								
	X-mas tree								
	LRP housing								
	LRP shear or seal ram								
	Subsea drilling BOP								
	Subsea drilling BOP shear or blind ram								
	Subsea X-mas tree								
	Well head								
	Prod. casing hanger								
	Production Casing								